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VOICE OF THE ELECTRIC UTILITY INDUSTRY

Record cold wave brings blackouts

Demand highs compound TX, FL generating problems; DSM helped

Mark T. Hoske
News Editor

How cold was it? That may sound like a comedy routine, but few people were laughing.

It was so cold that...

- Record peak demands resulted in rolling blackouts at Florida Power Corp. (FPC) and Florida Power & Light Co. on Dec. 24 and 25. Some areas were below freezing for three days, with several reaching zero.
- Tampa Electric Co., Jacksonville Electric Authority, Houston Lighting & Power Co., Lower Colorado River Authority, and San Antonio City Public Service were among other utilities that also had to institute blackouts during the cold snap.
- Utilities in regions able to meet demand also set winter and all-time electricity records, hitting demand peaks not expected until the mid- and late '90s.
- Warm-weather-minded engineers are rethinking some power plant designs that caused tripping during the record freeze, which was coupled with high winds. In some cases, changes were as easy as adding insulation to outdoor pipes.
- A number of utilities' natural gas customers experienced reduced flow for several hours because of high demand and resulting low pressure in gas lines. Some gas-fired generation without firm contracts was idled or capacity was cut by switching to fuel oil.
- Florida Gov. Bob Martinez declared the state a disaster area because of the loss of an estimated 30 percent of the citrus crop and severe damage to other crops, nurseries and tropical fish.
- Edison Electric Institute's tally of electrical output listed a total U.S. increase of 20 percent for the week ending Dec. 23, with the highest increase in the Southeast region, up 33.1 percent. For the week ending Dec. 30, total U.S. electrical output increased 12.8 percent, with the highest increase again in the Southeast, up 25.5 percent (see p. 3).

Electric space heaters

"Florida had extremely cold weather, the kind they don't normally plan for," explained Eugene F. Gorzelnik of the North American Electric Reliability Council (NERC).

"Because of the severity of the cold weather, everyone tried putting on electric heaters," he said. And that led to demand beyond available capacity.

The 1989 Reliability Assessment listed the winter peak for the Southeastern Electric Reliability Council region at 108,649 MW for winter '88/'89 and 114,642 MW for this winter. Gorzelnik said "a whole series of new peaks were set," although figures were not yet available.

NERC said in its '89/'90 assessment that "generation capacity in SERC over the next 10 years will be adequate to serve the projected peak demands and annual energy requirements" from 1988 to '98.

What happened? "It lasted longer and the temperature went lower than anyone could [economically] plan for," Gorzelnik pointed out.

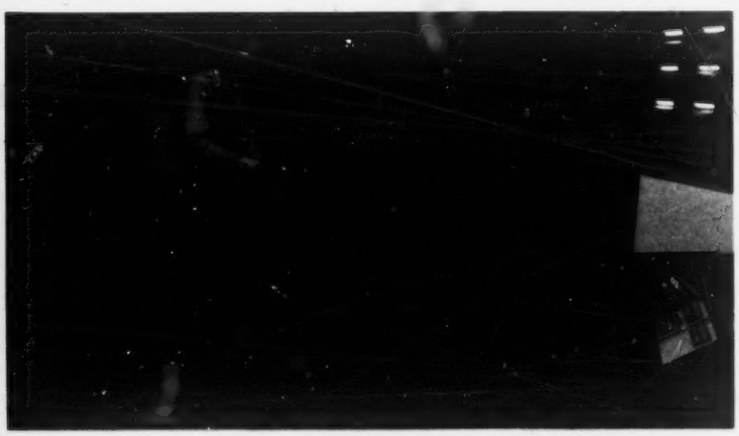
All in all, power supply problems could have been more widespread if the cold had not come over holidays, suggested Charles Wynn, administrative manager of Southeastern Electric Reliability Council (SERC).

Except for the Florida utilities, others in the region had peaks just a few percentage points over forecasts and were able to meet loads using demand management, he pointed out.

Wynn said that preliminary estimates show a peak for the Florida utilities, excluding Gulf Power Co., near 33,883 MW compared to a forecast of this winter of 30,412 MW, more than an 11-percent increase.

"Previously, cold waves were an over-

Continued on page 6



Across the South, utility personnel scrambled recently to meet record demands as a cold front swept over large regions. This state-of-the-art control center helped Tampa Electric Co. manage soaring demand, but the utility, like others, had to institute rolling blackouts to maintain system stability.

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ComEd rate hike nulled; Chicago threatens buyout

CHICAGO—Commonwealth Edison Co. officials—and state regulators—are reeling from a Dec. 21, '89, Illinois Supreme Court decision that reversed an Illinois Commerce Commission (ICC) six-year rate package.

The 1988 ICC decision gave ComEd a two-level, $480-million rate hike with a four-year freeze agreement.

"This decision really threw a lot of things up for grabs," said ComEd spokesperson John Hogan. "We had hoped to enter the new decade with this matter behind us."

In other, unrelated, news, ComEd officials can also expect to be busy with franchise negotiations with Chicago. The city recently announced intent to cancel its 42-year franchise agreement with the utility and threatened a buyout.

Continued on page 8

LATE NEWS

WEPCo vs. EPA—about binding life-extension projects to New Source Performance Standards—was decided Jan. 19 by the 7th U.S. Court of Appeals. Arguments were upheld on both sides. No decision was made yet on the delayed Port Washington Power Plant renovation.

Niagara Mohawk Power Corp.'s Nine Mile Point One nuclear plant reloaded fuel in early January.

Richard Snell takes over for Pinnacle West Capital Corp.'s retiring Chairman, President and CEO Keith Turley on Feb. 5.

PWCC turns away PacifiCorp's offer, seeks 22% rate hike

PHOENIX—Soon after Pinnacle West Capital Corp. (PWCC) turned down PacifiCorp's revised $2.08 billion offer for the financially troubled company, its Arizona Public Service subsidiary asked state regulators for a 22-percent, three-year rate increase.

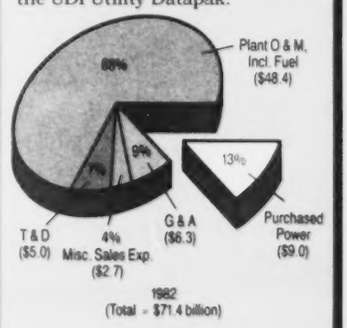
The increase seeks to put costs from Palo Verde 3 nuclear unit and coal-fired Cholla 4 into the rate base.

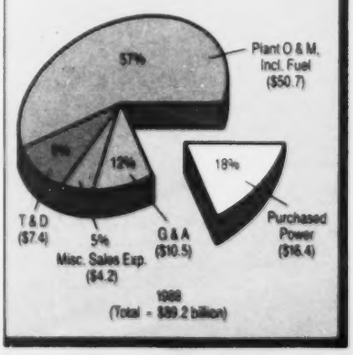
Regulators and PacifiCorp officials expressed disappointment at PWCC's moves and encouraged PWCC to reconsider the merger offer. PacifiCorp promised to hold rates to an 8-percent in-

Continued on page 8

ELECTRIC UTILITY OPERATION AND MAINTENANCE EXPENSES ($billion)

The percentage of operating and maintenance costs attributable to purchased power by 150 U.S. electric utilities is climbing, according to information supplied by the Utility Data Institute based on its database. Yet as a portion of total energy distributed, the number of purchased megawatthours has remained nearly constant at approximately 14 percent, as reported by the UDI Utility Datapak.





News Briefs

JILL MINNER, Special Projects Editor

Battelle forecasts 1990 R&D expenditures

In its annual forecast, Battelle expects 1990 research and development expenditures in the United States to reach $138.7 billion. This figure shows a $6.3-billion, 4.8-percent increase over the National Science Foundation's estimate of $132.4 billion actually spent for R&D in 1989, according to Battelle. A real increase in 1990 R&D expenditures of approximately 2.1 percent is also predicted by Battelle. "With significant global changes occurring in both the political and economic environment, we have every reason to expect that there will be continuing reallocation and reevaluation of R&D resources," explained Battelle President and CEO Douglas E. Olesen. "These changes offer both challenges and opportunities, and it remains for the R&D community to develop innovative ways of applying its store of strong and diverse talent," he added.

Massachusetts DPU proposes pacesetting regulations for utilities

The Masschusetts Department of Public Utilities recently proposed regulations for electric utilities to follow when planning for their future energy needs. "This proposal sets out a more effective way for the state to ensure that adequate resources are in place to meet anticipated demands for electricity," explained DPU Chairman Bernice K. McIntyre. The DPU proposed the following regulations: inclusion of environmental considerations in the criteria used to select resources; coordination with the Energy Facilities Siting Council; pre-approval of contracts for new generating facilities or for conservation and load management; and flexibility for utility companies in deciding which resources to use to meet energy needs of their customers. Public hearings on the proposed regulations will begin Feb. 28, 1990, and final comments are due ten days after the close of the hearings.

Idaho Power says rates too low for customers to receive credits

According to Idaho Power Co., its rates are so low that its customers don't qualify for credits under the Residential Exchange Program. The program is part of the Northwest Power Act which was designed to spread benefits of the Northwest's low-cost federal hydro power to customers served by private utilities. Idaho Power customers did not receive any of the $26.9 million that the Bonneville Power Administration said it paid during 1989 to Idaho residents served by private utilities. The utility said it has dropped from the program since Idaho Power customers would not receive benefits during the life of the agreement.

Conference Board's Outlook Panel predicts labor shortages in 1990

The Conference Board's Human Resources Outlook Panel has predicted that the U.S. economy will avoid a recession in 1990, but that companies will face widespread labor shortages and will be forced to hire people they would not have hired before. The panel, which includes ten labor experts, also projects that wages and salaries in private industry will increase by an average of five percent this year. Other panel predictions for 1990 include: unemployment will average 5.3 percent; the rate of inflation will average 4.5 percent; labor costs per unit of output in manufacturing will rise by about 2 percent; and manufacturing productivity will advance by about 3 percent.

Hydro flow rate case to be reviewed by U.S. Supreme Court

The U.S. Supreme Court has agreed to review a case that may have a strong impact on hydro project owners, according to the American Public Power Association. The case, which questions who has the authority to set hydro project flow rates, involves the Federal Energy Regulatory Commission, the state of California, and a 3-MW hydro project on Rock Creek. FERC specified interim water flow rates for the project in April 1983. However, in February 1984, the California State Water Resources Control Board issued a permit for the project reserving jurisdiction to set permanent rates. APPA said the 9th U.S. Circuit Court of Appeals later upheld FERC's jurisdiction.

NARUC publication helps consulting firms with utility audits

The National Association of Regulatory Utility Commissioners said it has released a publication, *Consultant Standards and Ethics for Performance of Management Analysis*, to guide consulting firms on the special circumstances of a utility audit. According to NARUC, consultants contracting with public utility commissions and/or utilities would benefit from the 16-page report. The report is broken down into three parts: Part A discusses general standards for a management audit of a utility; Part B covers the examination itself and workpaper standards; and Part C discusses reporting standards. For a copy of the report, which costs $6.50 per copy, contact NARUC, P.O. Box 684, Washington, DC, 20044.

EARTHTECH '90 to focus on environmental problems and solutions

A large-scale technology fair and international policy forum, EARTHTECH '90, will be held April 4-8 in Washington, DC. Created by Sens. John Heinz (R-Pa.) and Al Gore (D-Tenn.) and the Environmental and Energy Study Institute, the event is designed to encourage solutions to global environmental problems. The fair will allow corporations, government agencies, and small entrepreneurs to showcase existing and new technologies, products and strategies for environmentally sustainable development. The forum will include discussions by corporate leaders, government policy makers, and public interest representatives on ways to accelerate innovation and bring environmentally sustainable technologies into widespread use.

EEMI helps engineers, managers with energy, environmental issues

The Association of Energy Engineers has announced the formation of the Environmental Engineers & Managers Institute (EEMI). The institute aids engineers and managers by covering environmental and management issues, and providing a forum for the exchange of technical, legal and managment information in all segments of the market, according to AEE. Subjects covered in EEMI programs include: global warming and its effect on energy programs; ozone depletion and CFC limitation; underground storage tanks and spill prevention; water and air pollution; waste to energy; toxic substances; sludge; radiation; and asbestos removal. For membership information contact: AEE Environmental Engineers & Managers Institute, 4025 Pleasantdale Road, Suite 420, Atlanta, GA, 30340.

ASME names president

The American Society of Mechanical Engineers has chosen Arthur E. Bergles to serve as president starting in June 1990. Bergles is Rensselaer Polytechnic Institute's Dean of Engineering, and has been an active ASME member since he was elected a Fellow in 1979.

Westinghouse acquires LN Technologies Corp.

According to Westinghouse Electric Corp., it has acquired the assets of LN Technologies Corp., a provider of chemical decontamination and low-level radioactive waste processing services for the nuclear power industry. "LN Technologies provides the most widely accepted chemical decontamination services in the industry. In addition, its radioactive waste processing capabilities are an excellent complement to our existing products and services in this area," stated Thomas A. Christopher, general manager of the Westinghouse nuclear services division. Westinghouse said it plans to consolidate the product lines with existing service activities offered by its nuclear services division.

PG&E wins award for equal employment

The U.S. Department of Labor honored Pacific Gas and Electric Co. with its 1989 Opportunity 2000 Award. U.S. Secretary of Labor Elizabeth Dole presented PG&E President George A. Maneatis with the award, in recognition for the utility's national leadership in affirmative action and equal employment opportunity programs. The utility said it spent over $1.3 million in 1989 on more than 50 outreach, educational and employee empowerment programs. "We are convinced that this investment in equal opportunity pays high dividends in the health and vitality of the communities we serve. And when communities prosper, business prospers," stated Maneatis.

MGE offers energy conservation rebates

According to Madison Gas and Electric Co., all of the businesses it serves are now eligible for new energy conservation services and incentives, including cash rebates. Rebates are available for improvements in lighting, water heating, electric motors, space-heating equipment, refrigeration equipment, air conditioners and more. MGE said incentives cover about 25 to 50 percent of the project materials and installation costs.

Utilities fined by NRC

The U.S. Nuclear Regulatory Commission recently proposed the following fines:

Consolidated Edison Co.
A $50,000 fine for failure to promptly correct a weakened emergency preparedness plan at the Indian Point 2 plant.

Duke Power Co.
A $50,000 fine for alleged violations of NRC security requirements at the Catawba, McGuire and Oconee nuclear power plants.

Florida Power Corp.
A $50,000 civil penalty for alleged violation of NRC requirements at the Crystal River nuclear power plant.

Northern States Power Co.
A $3,750 fine for violations of NRC security and reporting requirements at the Monticello nuclear power station.

Washington Public Power Supply System
A $50,000 fine for alleged violations of NRC requirements involving the procurement program for the Washington Nuclear Project No. 2.

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Stockholders vote on NU's PSNH buyout; Seabrook is ready

Legislature OK'd NU rate boost for PSNH Jan. 1

MANCHESTER, NH—Stockholders and creditors are now voting on the $2.3-billion Northeast Utilities Co. offer for Public Service Co. of New Hampshire.

PSNH customers already tasted the beginning of NU's plan after state lawmakers approved a seven-year rate increase. State regulators then approved an interim increase of 5.5-percent that became effective Jan. 1. The New Hampshire Public Utilities Commission is working out details on seven years of such increases with a three-year freeze after that. Both PSNH and NU representatives are fairly confident the rate plan will go through.

On Jan. 19, stockholders and creditors were mailed ballots on the NU offer that would make PSNH an NU subsidiary. Their deadline for response is March 7. With approvals, confirmation hearings on the offer should begin at the PSNH bankruptcy court on April 4.

NU is seeking Federal Energy Regulatory Commission and Securities and Exchange Commission approvals.

FERC intervenors are expected to voice concern over transmission issues and "open access." The industry may see a second wheeling agreement, as FERC required of PacifiCorp when it acquired Utah Power & Light Co.

Approval will be needed from the Nuclear Regulatory Commission because the operating license of Seabrook would change from PSNH to NU. NU seeks to set up three subsidiaries, said company spokesperson Jeffrey R. Koktin.

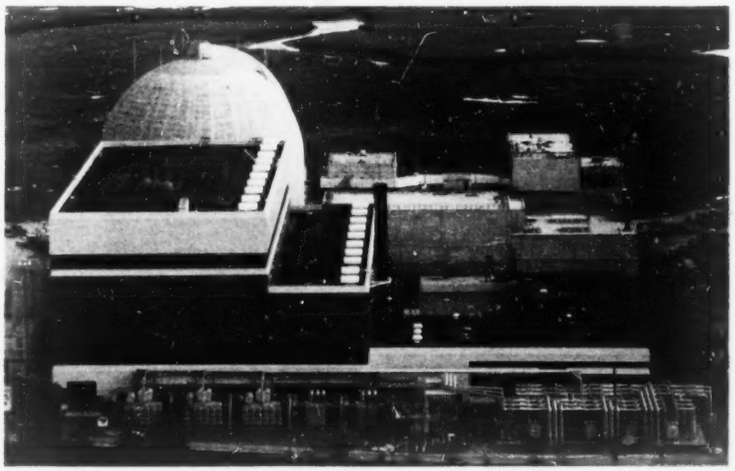
PSNH would retain its name as a subsidiary. Northeast Utilities Operating Co. would operate Seabrook, and North Atlantic Energy Corp. would own the PSNH share of Seabrook.

The plant now awaits full-power operation under a PSNH division called New Hampshire Yankee (NHY).

A majority percentage of Seabrook owners would have to approve an operator change. NU seems confident about that—after the PSNH buyout it will own about 40 percent (see related story).

NU is no stranger to nuclear operations, already owning 44 percent of Connecticut Yankee and 65 percent of Millstone 3, and operating both plants. NU also operates Millstone 1 and 2.

The buyout plan includes employment and benefit guarantees for 18 months for all PSNH employees except the top 60 managers and the top five executives (and NHY division personnel who are employed by the joint Seabrook owners.) The top five PSNH executives would resign upon confirmation and the top 60 would know their job status within two months of confirmation, said PSNH's Nicholas Ashooh.



Seabrook plant operator—New Hampshire Yankee—told the Nuclear Regulatory Commission officials that Seabrook is ready to go. The NRC had said the full power license could come soon after that Jan. 18 briefing. The long-delayed 1150 MW of capacity is sorely needed in New England.

If everything goes as scheduled, stockholders and creditors will own the company in May or June as a result of the bankruptcy reorganization, Ashooh said. They would execute an agreement with NU to manage the company until final buyout approvals are secured. Koktin said NU hopes to own PSNH by the end of July.

On Dec. 13, 1989, the PSNH board endorsed the NU proposed acquisition after several weeks of intense negotiation between managements at both companies (*EL&P*, Jan., p.11). Creditors' and stockholders' representatives had previously agreed to NU's boosted bid. PSNH management long-hoped to remain independent.

Under the current NU plan, PSNH secured creditors would receive all the principal and interest owed them. Unsecured creditors would receive all the principle and all the interest up until the time of filing, plus about one-third of the interest accrued since the bankruptcy protection filing.

Equity holders—preferred and common shareholders—will get a combination of cash and securities with total value of $430 million (about $3-4 per share, Koktin said), if Seabrook operates and $205 million less if it doesn't.

Equity holders also get opportunities to buy a total of 8.4-million shares of NU stock for $24 each for up to five years. NU is now trading at $22.

NU's orginal PSNH bid was $1.9-billion. United Illuminating and New England Electrical System also had placed bids (see *EL&P*, Dec.'89, p.3). NU first expressed interest in purchasing PSNH assets in March '88. In July '89, NU reached an agreement in principle with the state to maintain PSNH rates about equal with inflation for seven years.

PSNH has been reorganizing under bankruptcy protection since January 1988 due to non-payment of debt from a 36.5-percent share of the Seabrook nuclear plant.

Hartford, CT-based NU is New England's largest utility system serving about 1.25-million customers in Connecticut and western Massachusetts. PSNH serves about 365,000 customers covering 75 percent of New Hampshire.

See also a story on PSNH cost cutting and efficiency, p.27.

In an unrelated development, George Branscombe, vice president and treasurer, is now heading the reorganization, having succeeded Charles Bayless as PSNH senior vice president and chief financial officer. Bayless is now Tucson Electric Power Co.'s senior vice president and chief financial officer.

Long-stalled nuclear plant is ready to go

SEABROOK, NH—The Seabrook nuclear power plant operator, New Hampshire Yankee, was expected to tell Nuclear Regulatory Commission officials that their long-delayed nuclear power plant is ready to go, at a Jan. 18 briefing at NRC headquarters in Rockville, MD.

NRC officials said a vote on a full power license would come at a later meeting, possibly by the end of January.

But even if found structurally and operationally sound, the politically embattled plant may face further delay. The Massachusetts attorney general is likely to seek a last-minute court stay of the license through the U.S. Appeals Court in Washington.

State leaders in Massachusetts have long opposed the plant, saying that the portion of the 10-mile emergency preparedness zone in Massachusetts could not be safely evacuated.

Construction on the 1150-MW reactor began in 1976. It has cost a consortium of utilities more than $6.35 billion; over one-third of that is interest. The NRC granted the low-power license in May 1989. NHY officials hope to be producing electricity within the first quarter.

The 11 owners include: PSNH with 35.6 percent; United Illuminating Co., 17.5 percent; EUA Power Corp.(Eastern Utilities Associated), 12.1 percent; Massachusetts Municipal Wholesale Electric Co., 11.6; New England Power Co., 10 percent; and Connecticut Light & Power Co. (Northeast Utilities), 4.05 percent.

Boston Ed settles some Pilgrim suits

BOSTON—Boston Edison Co. settled litigation with three of 16 wholesale customers relating to BE's 32-month Pilgrim Nuclear Power Station outage.

With previous settlements with other customers, BE listed a $100-million after-tax charge against 1989 fourth-quarter earnings. Because of a $70-million reserve set aside for additional settlements, the year-end charges total $170 million, resulting in a year-end loss, BE reported. The utility cut its quarterly dividend from 45.5 cents to 35 cents.

The Jan. 1 agreement settles matters with Commonwealth Energy System's Commonwealth Electric Co., Montaup Electric Co., and Municipal Light Board of Reading, MA.

The contracts, in place since 1972, require the purchasers to pay proportional shares of Pilgrim's operating and capital costs. In 1987, these customers filed complaints with FERC seeking termination of contracts and damages.

In addition to a revised contract, the companies also receive money for replacement power and court costs.

Approvals from the Federal Energy Regulatory Commission and the state Dept. of Public Utilities are expected.

Pittston, UMW expect end to 9-mo. coal mine strike

GREENWICH, CT—By the end of January, Pittston Co. and United Mine Workers expect a vote from the union rank and file on an agreement that could end a bitter nine-month coal-mine strike against the company.

If the 1900 striking miners agree to the settlement, Pittston will likely see higher productivity than companies that settled when UMW negotiated a 1988 contract. Striking Pittston mines stayed open, although output fell and some customers bought elsewhere.

Both sides agreed to silence on contract details until after the vote. Speculation on details has been widespread since the tentative settlement was reached Dec. 31, '89.

Talks had stalled due to differences about health benefits, pension plans and job security measures. Pay was not an issue. Both sides had hoped to provide incentives to increase miner productivity.

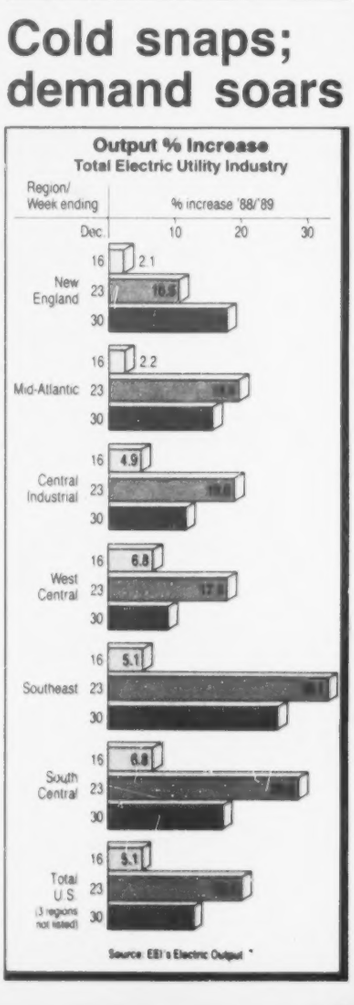
Although sympathy strikes, violence and related work stoppages did disrupt some supplies, it was not enough to hamper utility coal supplies (see *EL&P*, Aug.'89). These labor actions were at Eastern mines, affecting as many as 50,000 miners in nine states.

"I think everyone will be surprised," said Pittston spokesperson W.J. Byrne about the speculation on the contract.

He called it a "win-win agreement," adding that both sides the decision to be ratified. "It's a new way of doing business in the '90s," Byrne added.

Various analysts estimated Pittston's losses from the strike at $60 million, but Byrne said the number is more like $30-40 million.

Cold snaps; demand soars



COMMENTARY

No more Seabrooks, please...

The prospect of the Seabrook Nuclear plant finally starting up—after 14 years of bitter debate and countless delays—is heartening to the entire electric utility industry. Many utilities have suffered right along with Public Service Co. of New Hampshire, albeit at a distance...a case of being tarred with the same brush. If there is to be a nuclear future for this industry, it would seem that the Nuclear Regulatory Commission should find a way to ensure that the kind of disasterous administrative and judicious delays that have battered PSNH aren't allowed to happen again...ever.

Seabrook's delay in coming on line, and costs that skyrocketed to $6.3 billion-plus, pushed PSNH beyond the financial breaking point, bankruptcy and reorganization under Chapter 11 protection. It thrust financial hardships and regulatory pressures on other Seabrook co-owners. Other utilities completing nuclear plants also incurred delays and added costs because of the ripple effect of Seabrook.

Now the prospects appear good for Seabrook to receive its full-power license ... perhaps by the time *EL&P* subscribers read these observations. But it's far from sure. There still remains the potential for Massachusetts Attorney General James Shannon to seek a further delay to operation of the plant through the U.S. Court of Appeals in Washington.

Therein lies the continuing rub...and the problem that NRC must solve. At every turn, Massachusetts officials have done whatever they could to delay Seabrook. Never mind that the State of New Hampshire had given its approval, and accepted the minimal risk acknowledged by scientists and regulators. Never mind that the most comprehensive and stringent efforts had been extended into researching, designing and engineering the comprehensive safety measures engineered into the plant, safety procedures and systems subsequently subjected to minute, in-depth inspection, tests and evaluation by the most qualified scientific and engineering minds available. Never mind that emergency plans meeting NRC criteria were developed by the Seabrook emergency planning team, despite Massachusetts state and local officials' refusal to participate in those studies and plans.

The delays brought about by Massachusetts officials will be paid for by New Hampshire ratepayers for decades. The increased costs of the power from Seabrook, power desperately needed in New England to meet steadily increasing demand growth, also will be paid for by residents of other New England utilities. In capital-intensive projects such as this, delays impose severe financial burdens, and, in the worst case, lead to abandonment.

Some way must be found to prevent such dilatory tactics from occurring again. If delays are necessary, procedures should be developed to make those responsible for the delays financially liable for the increased costs if it's determined that their objections are without merit. It has been too easy to intervene and to halt progress of a project on the basis of even the most illusionary "threats of danger" or other possible negative factors.

One-stop licensing is held out as an almost magical way to renew the nuclear option. But without rules that make intervenors financially responsible for the effect of their actions, even this may not be enough.

The industry can't afford another Seabrook. New Englanders, thanks to Massachusetts, will be hard-pressed to afford the one they've got.

Robert A. Lincicome, Editor-in-Chief

Good investments deserve to earn

Commonwealth Edison Co. has long drawn heavy criticism for building 12 nuclear units that currently supply 70 percent of its customers' electrical needs. Most recently, CECo suffered severe setbacks in implementing rates for its last three nuclear units, $7.1 billion in investments (see p.1), despite a hard-fought compromise plan by regulators.

While ComEd's nuclear program has created some of the highest rates in the country now, it has ensured an adequate energy source when other areas of the country are capacity short. In addition, if stringent Clean Air legislation is implemented, ComEd may laugh all the way to the bank. It could then sell clean nuclear-generated power to Midwest utilities faced with the possible alternative of installing high-cost scrubbers on old coal-fired units.

Mark T. Hoske, News Editor

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LETTERS

A few good (oops) men

I really look forward to reading your magazine every month. The subject material is well chosen for interest and use, the writing is excellent and the presentation is inviting.

I was surprised to find commentary of this type [See "Call for papers," Nov. *EL&P*, p.22c, subheaded "A few good men," in which the desire of the Cogeneration & Small Power Production Technical Committee of ASME to attract more "people" [meaning men and women] was described.] and, as one might expect, was not pleased!

Denise Margaret Zurn, P.E.
Minneapolis, MN

Editor's note: Ms. Zurn was first, but far from being alone in calling our attention to the now inappropriate use of the term "men" instead of a more non-sexist term, such as people or engineers. Ah, we try...but we're mere mortals and too often err. Apologies to all our feminine readers.

Who has the guts to do what?

Editor's note to "A Supplier:" We would be happy to publish your letter, in which you questioned if we had the guts to publish your comments, had you only displayed the similar intestinal fortitude to sign your name. While we will withold publishing the name of any letterwriter upon request, we will not print letters from anonymous sources.

Greenhouse effect?

Pop the top on an ice-cold can of beer and there's a nice crisp spritz. Pop the top on a can of beer that's been sitting in the car trunk on an August day and there will be a not-so-unexpected beer shower. Why? Carbon dioxide is not as soluble in warm liquid as in cold.

Set a pan of water on a stove burner to boil and, as the water heats up, visible vapor appears above the water's surface.

Scientists have discovered that atmospheric gases trapped in thousand-year old ice may have a lower concentration of carbon dioxide than at present. Many claim that the earth was cooler [then] because there was less CO_2 in the atmosphere and hotter now because there is more. However, like the chicken or the egg, which came first?

If the earth is cooler, more CO_2 will be absorbed in the oceans and less will be [present] in the atmosphere, as found in the ice packs. The amount of cloud-forming vapor also will be lower, letting in more warming sunlight. As the earth begins to warm up, heat-trapping CO_2 concentrations increase, but earth cooling water vapors also increase. The earth will heat or cool until it reaches a natural equilibrium, even if that is comparable to Venus or Mars. This greenhouse cycle can be and has been interrupted by other natural occurences: the Apollo asteroid that chilled out the dinosaurs, Krakatoa and Mt. St. Helens, the Tunguska comet, the Yellowstone fires, nuclear war. But once the dust settles, the laws of physics and thermodynamics remain unchanged.

If increasing CO_2 levels are the cause, and not the result, of atmospheric heating, man's five-billion ton annual production is negligible in a 6.5 million billion ton atmosphere. With a 50 percent recycle rate by vegetation and ocean, man's contribution is only 40 percent of the one part-per-million trend detected at the Mauna Loa test site. So where is the rest coming from and how are we going to stop it? The quadrillions of energy Btus converted to useful and useless purposes, all of which heat up the atmosphere, could account for half the temperature rise. *Changing energy sources won't change that* [emphasis provided]!

Is the earth heating up? Could be, but so what? Tree-ring records show the earth has heated and cooled for thousands of years. Geological and fossil records show the earth has heated and cooled for millions of years without the help or hinderance of fossil fuel burning, forest clearing or industrialized man.

Two special interest groups have lined up on Capitol Hill: government-grant professionals waiting to stay comfortably employed, and coercive utopians seeking to put us all in solar homes, on bicycles and off Argentinian beef. Our elected representatives, who have mucked up everything they have touched for 200 years, now are going to prove their worth by squandering our tax dollars trying to control the weather. Ozone holes, global warming, the greenhouse effect, fossil-fueled carbon dioxide and man's ability to damage and repair the atmosphere are collectively the biggest carnival hustle and snake-oil promotion since a geocentric universe spun around a flat earth.

This entire issue revolves around man's enormous ego, a belief that his meaningless existence on this little dust ball in space has some sort of cosmic importance. Nature would gladly stop by and, with total regard for government regulations and programs, pinch off all our pointy heads with nary a backwards glance.

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Boulder, CO

JPGC comment and report

Two articles which appeared in the December 1989 edition of *Electric Light & Power* cannot escape comment. I am referring to an article entitled, "JPGC Breaks Little New Ground," which appeared on page 16 and the follow-up article appearing on page 19 entitled, "Power-Gen '89 Opens December 5 in New Orleans."

Just to set the record straight: the Joint Power Generation Conference has a long-standing tradition and reputation for excellence in the content of its technical program. Sponsored by the ASME and IEEE, the technical information presented at the JPGC is developed by industry professionals, reviewed by members of the sponsoring societies, and represented to the technical community at minimal cost to those in attendance.

The content of the 1989 JPGC and the 20 or so previous JPGCs represent the best available technical information from over 200 authors. All of the papers are contributed by professionals in the field of power generation facilities design, operations and maintenance. Countless other power industry professionals participate in the topic selection, paper reviews and conference arrangements.

The Joint Power Generation Conference sponsors papers on all phases of the power generation field.

To imply that the content of the JPGC in 1989 or any other year is not all inclusive of the power generation industry or is less than timely, is editorializing in the guise of reporting the news.

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How NUG capacity is growing

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Senior Vice President
RCG Hagler, Bailly Inc.

Focus
Non-Central Station Power

In the last 10 years, almost 2500 non-utility generation (NUG) plants mushroomed up in the United States. These plants, which are not ratebased, include self-generation plants, qualified facilities (QFs) and independent power projects (IPPs).

These and future NUG power plants will provide some 45 percent of the new generation capacity to be built in the U.S. over the next seven years.

Self-generation plants are built by industrial or large commercial users to meet their onsite power needs and generally do not interface with the power grid unless it is on a seasonal basis.

QF projects, in contrast, sell power to the grid under long-term contracts at rates negotiated with the buying utilities and approved by state regulatory commissions. QF owners are not, however, regulated as utilities, if they satisfy the size and fuel conditions of the 1978 Public Utility Policy Regulatory Act (PURPA). QFs must be either qualified cogeneration facilities (of any size or fuel as long as they produce at least 5-percent useful steam) or small power projects that use alternative sources of energy and are in sizes below 30 MW (normally) or 80 MW (depending on fuel; e.g., 80 MW for culm or municipal solid waste).

IPPs are a newer type of NUG project that do not meet the PURPA conditions but still escape utility regulation through specific exemptions of the Public Utility Holding Company Act that are granted by the Securities & Exchange Commission.

RCG/Hagler, Bailly estimates that 31,000 MW of new NUG capacity will have been developed between 1988 and 1996. The projects will be diverse in terms of size, fuel and ownership. To build this, a new power industry will emerge that will be a mix of both non-utility entities and unregulated subsidiaries of electric utilities.

Current situation

NUG power has grown by 15 percent annually since 1980 (see Fig. 1). After a timid start between 1980 and 1983, when annual NUG capacity additions slowly grew from 600 to 1300 MW, the market took off in 1985 when capacity additions neared 3000 MW. Since then, between 3000 and 4500 MW have been added each year. Overall, NUG plants have provided 15 percent of the power generation added in the U.S. since 1980.

At the end of August 1989, 27,851 MW of NUG capacity was in-place, with an annual production of 145,000 GWh, about half sold to the grid. The majority of that capacity, over 19,000 MW, is made up of QF projects. IPP projects are few, with only three operating (totaling 1058 MW). There also is some 7600 MW of pre-PURPA, self-generation capacity.

Figure 1. Non-Utility Generation Growth

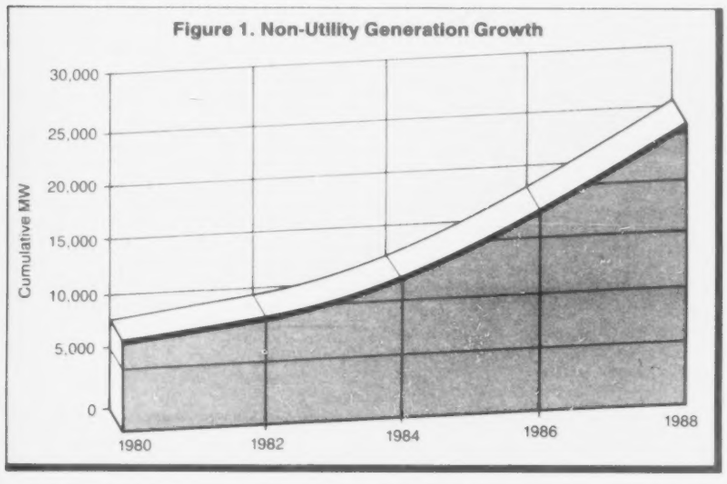

Table 1. Non-Utility Generation (August 1989)

Primary Energy Source	Projects	Capacity (MW)
Natural Gas	902	12,685
Oil	43	412
Coal	82	3,854
Waste Fuel	50	1,904
Wood	137	2,379
Agricultural Waste	21	181
Biomethane	98	481
Other (hydro, MSW, solar, wind)	1,121	5,955
Total	2,454	27,851

Current fuel mix

NUG projects use a variety of energy sources (see Table 1) in eight categories: natural gas, oil, coal, waste fuels, wood, agricultural waste, biomethane and others (such as solar, hydro, wind and municipal solid waste).

Gas-fired plants dominate, with 45 percent of the operating NUG capacity. Next come facilities burning coal (bituminous, subbituminous, lignite and anthracite) or wood (wood chips, bark and sawdust). Together, they account for 22 percent of the NUG market.

While most wood projects are between 10 and 25 MW, coal projects tend to be between 30 and 50 MW. Waste-fuel-fired projects come in fourth, with 7 percent of the total capacity, thanks to a fairly large average project size (around 40 MW). Waste fuels include petroleum coke, refinery gas, coal mine waste, anthracite culm, coke-oven gas and blast-furnace gas.

The balance of the NUG universe consists of some 1240 smaller projects (totaling 6600 MW) that use hydropower, municipal solid waste (MSW), solar and wind power, geothermal, agricultural waste, and biomethane. This includes some 1400 MW of hydropower, 1200 MW of MSW, 1000 MW of wind and solar, and 760 MW of geothermal projects.

In the last three years, the proportion of new gas-fired capacity stabilized between 48 and 52 percent of total new NUG capacity installed each year (see Fig. 2). At the same time, the proportion of coal projects decreased from 18 to 10 percent. The proportion of MSW averaged 7-8 percent of annual NUG additions, and the share of solid non-MSW projects rose steadily.

Regional developments

NUG power has developed unevenly across the United States, independent of the distribution of existing population or electric loads. To date, two regions have captured 58 percent of total NUG capacity in-place. First, the West-South Central Region (basically Texas) claims nearly 8960 MW of NUG plants, a large part as petrochemical cogeneration plants. Second, the Pacific Region (95 percent of which is California) has about 6800 MW of the capacity, including large cogeneration facilities for enhanced oil recovery fields and many smaller geothermal, wind, small hydro and wood-fired projects.

Both regions have been active through 1988. Over 1200 MW came online in 1987 in the West-South Central Region alone, and the Pacific Region experienced a record in 1988 when 1800 MW of new NUG power hit the grid. These two regions are, however, entering a phase of partial cooldown.

Now other regions are entering the picture more strongly. The South Atlantic Region ranks third, with 3300 MW of NUG capacity in-place in Florida, North Carolina and, more recently, Virginia. Lately, the Mid-Atlantic and New England Regions also have become active in the field. In contrast, the East-North Central Region, with only 1655 MW of mostly industrial-based cogeneration, has not been very active.

With different levels of market development across regions come different fuel mixes (see Table 2). Natural gas-fired capacity dominates the NUG market in the West-South Central and Pacific Regions, while coal's share in the South Atlantic and East-North Central Regions exceeds or is close to 50 percent. New England exhibits the greatest proportion of biomass facilities (71 percent), while the Mid-Atlantic Region shows a balance among gas, coal and waste fuel projects.

Table 2. Fuel Distribution of Non-Utility Generation (% - August 1989*)

Region	Natural Gas	Oil	Coal	Waste Fuel	Biomass
West-South Central	86	—	1	10	3
Pacific	73	2	4	5	16
South Atlantic	7	—	54	9	30
Mid-Atlantic	46	4	26	18	6
New England	17	10	2	—	71
East-North Central	16	7	47	17	13

*Excludes Hydro, MSW, Solar and Wind

Current NUG industry

The current industry is diversified. The RCG/Hagler, Bailly database identifies some 150 active players, including 55 project developers, 40 electric and gas utility subsidiaries, 25 equipment suppliers, 15 architect-engineering and construction companies, and 15 gas or coal suppliers. The analysis reveals that the 10 largest players control 40 percent of the action and the next 10, another 26 percent. The largest players have positions in 25-30 projects with a total capacity over 1500 MW.

In spite of strong capacity growth, the NUG power industry faces several challenges. First, it still needs to establish a track record in terms of project completion and capacity availability.

Second, NUG producers are struggling to get customers to accept a greater share of risks. The producers often are being asked to supply availability and heat rate guarantees while being dispatchable, providing subordinated debt, and, naturally, remaining the cheapest power supplier.

Consequently, NUG plant owners have taken risks on solid-waste facilities, wood-fired small power plants, landfill gas recovery and waste-coal projects. Problems are accentuated as NUG companies deal with a diverse slate of technologies, some of them as innovative as fluidized-bed combustion. The risk of hefty write-offs can quickly cause problems if NUGs become technology provers at a time when increasing competition rules risks out.

Next, NUG companies have to equip themselves with a qualified staff, including regulatory intelligence analysts, site specialists, transmission engineers, environmental specialists, and O&M trainers.

Finally, the industry is learning how to grow. Several companies are groping for ways to smooth the transition between current project portfolios of 250-300 MW and those approaching 1000 MW. In some cases, this means an annual revenue growth in excess of 35

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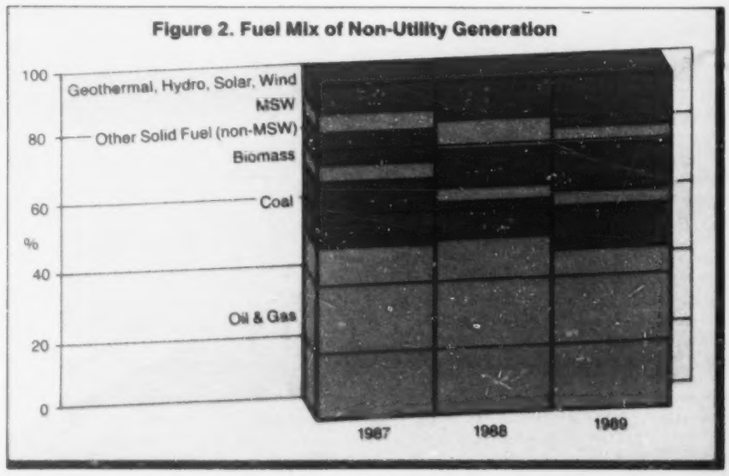
Figure 2. Fuel Mix of Non-Utility Generation



Operating and maintaining cogeneration gas turbines

E.J. Walsh
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The cogeneration industry is approaching a significant O&M milestone this year. The first-generation gas-turbine power projects are just about at the end of their first major maintenance cycle. As the next major cycle is entered, the effects of first-round maintenance strategy will become evident.

A review of O&M practices for heavy-duty gas turbines at cogeneration plants is now due, with the emphasis on the types of inspections, plus operating factors that influence maintenance schedules.

Advanced planning for maintenance is a necessity where downtime must be kept to a minimum. Control of planned maintenance and inspection provides direct benefits in reduced forced outages and startup failures, which in turn, reduce unscheduled repair downtime. A typical maintenance program must include a variety of essential items.

Types of fuel—Fuels burned in gas turbines affect maintenance (See Fig. 1). A maintenance factor of one in the tables signifies costs normal for natural gas operation. The other factors are multiples of this base cost. Heavier hydrocarbon fuels frequently contain corrosive elements that can reduce combustion hardware life. The cleanliness of liquid fuels (i.e., lack of salt water, lead and dirt) also affects the life of gas turbine auxiliary components.

Making the supplier meet a fuel specification or establishing a regular fuel quality sampling-and-analysis program are just two of several options available to an owner to minimize or eliminate adverse effects of unclean fuel.

Fired hours and duty cycle—Interaction between the gas turbine system and other major subsystems—fuel delivery, controls, turbine nozzles, buckets, rotors—determines the operating state of the turbine unit and significantly influences turbine maintenance requirements. The load cycle of the gas turbine (see Fig. 2), up to its continuous-duty rating, has little effect on the life of parts, provided it does not undergo frequent and rapid load changes. The effect of rapid and frequent load changes on a unit is similar to the effect of frequent starts and stops.

Each start and stop subjects the hot-gas-path parts to significant thermal cycles. The gas turbine control system is designed to minimize this effect. However, starting and stopping a turbine frequently shortens part lives and results in maintenance intervals that are shorter than a similar unit in continuous duty.

In general, for units in continuous duty, the starting effects are negligible, since few turbines in this service see less than 150 hr of operation for each start.

Maintenance practices—As operating and maintenance data are accumulated on a specific application, the next step in a well-planned program of outage management should be inspection intervals. Inspection intervals for optimum turbine service are not the same for every installation. Rather, each user develops intervals through an interactive process based on past experience and trends indicated by the key turbine factors.

Replacement parts—Achieving minimum downtime requires that replacement parts, either new or reconditioned, be available.

Bolting—Typically, about 25 percent of the downtime required for a hot-gas-path inspection is consumed removing and replacing flange bolting. Therefore, using correct tools and techniques during maintenance, such as thread deburring and control of tightening torques, dramatically improves followon maintenance activities.

Air quality—Airborne contamination (dust, salt, etc.) can cause compressor blading erosion, fouling, corrosion of components in the hot-section parts, and consequent reduction of lives of the parts.

A corrosive atmosphere can have a noticeable impact on compressor inlet guide vanes and compressor blade life. Annual inspection of the inlet areas is strongly recommended.

Compressor environment

The importance of inlet air quality can best be appreciated by considering that a gas turbine operating at a 12:1 pressure ratio ingests over 6000 lpm of air for every megawatt of power produced. Compressor degradation can occur from contaminants such as sand and mineral dust, which can cause blade erosion, fouling and damage from foreign objects.

Compressor fouling is often caused by ingestion of material that adheres to its components—material such as oil vapor, smoke, sea salt and industrial vapors. Axial-flow compressor deterioration is the major cause of loss in gas turbine output and efficiency. Typically, 70-80 percent of performance loss is attributable to fouling of compressor blades.

Fortunately, much can be done through proper O&M procedures to minimize such "recoverable" losses, such as effective compressor cleaning when needed (see Fig. 3), a well-maintained inlet-air filtration system, periodic inspection, and prompt repair of compressor blading.

Maintenance overview

Since maintenance costs and availability are two of the most important concerns to the owner, a rigorous maintenance program must be instituted that minimizes costs and maximizes equipment availability. For a program to be effective, the owner must develop an understanding of the relationship between his/her operating plans and priorities for the plant and the manufacturer's recommendations regarding number and types of inspections, spare parts planning, and major factors af-

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Figure 1. Estimated Effect of Fuel Type on Maintenance

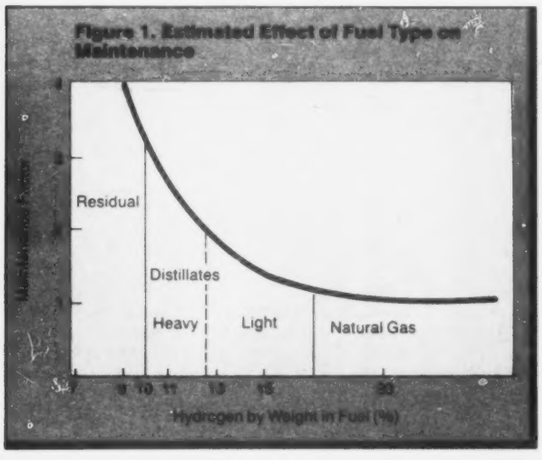
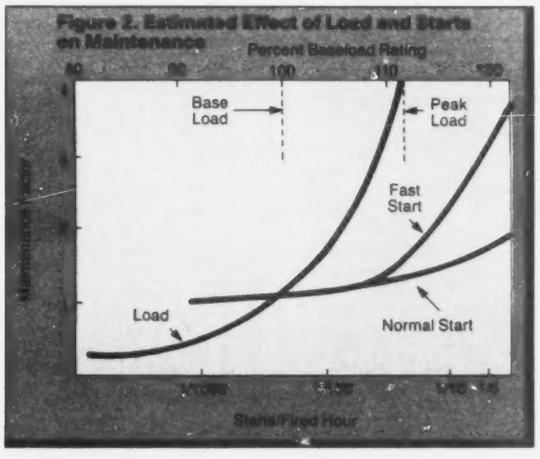


Figure 2. Estimated Effect of Load and Starts on Maintenance



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NUG capacity...

percent over the next three years.

This puts substantial pressure on their managements, especially if any are public companies that have to live within the "fishbowl" environment of quarterly reports. As a result, most of these companies are reassessing their strategies in terms of project mix, geographic focus and roles to play.

Future NUG generation

The database shows that some 614 NUG projects (25,000 MW) are under development. Only half of these, however, are likely to be completed because many will not secure the right fuel, technology or financing. The industry, however, will respond and propose at least another 20,000 MW of capacity through 1996 to replace earlier casualties.

RCG/Hagler, Bailly projects a net addition of 36,100 MW of NUG power between 1990 and 1996, broken down as:

- Some 23,200 MW (nearly 69 percent) will be in the form of gas- or coal-fired industrial cogeneration projects, in standardized designs, in sizes between 50 and 150 MW. After peaking for the next 2-3 years, gas-fired NUG capacity will decrease in the mid-1990s when solid-fired capacity regains momentum as developers offer to sell "clean-burning" power.
- About 7400 MW will be small power projects burning, for example, waste coal, MSW, wood, tires or agri-waste.
- Between 17 and 20 IPP projects (5500 MW) will come online by 1996. During the next seven years, the IPP growth will be timid and primarily in eight states, mostly along the East Coast.

Capacity gap

By bringing nearly 750 new projects online by 1996, the industry will help fill the U.S. capacity gap. At the end of 1996, over 57,000 MW of NUG capacity will be in-place, producing nearly 280,000 GWh/year.

A growing NUG capacity means an increasing choice of power purchase options for utilities. NUG producers offer firm, more or less dispatchable power, in sizes from 10 kW to 500 MW.

Utility subsidiaries

The future growth of the NUG market will cause some companies to become large, with project portfolios of more than 2500 MW by 1996. By then, the five NUG leaders may together control over 16,000 MW. These industry leaders will each have annual revenues approaching the billion-dollar mark.

At the same time, there will be a lot of losers, and the industry will shrink from its 150 current players to less than 90 by 1996. To stay in the game, the average company will have to grow by 15-20 percent per year and control more than 500 MW of project equity positions by 1996.

Utilities will play an increasing role in the NUG industry through their unregulated subsidiaries that benefit from several competitive advantages. First, utility subsidiaries have access to impressive internal engineering, construction, procurement and regulatory talent that they can tap as needed.

Second, thanks to their parents, these subsidiaries have access to capital. Better front-end project development money is generally available to them, a most useful resource when responding to competitive bids. In the long run, utility subsidiaries may have the strongest staying power, have the best understanding of transmission issues, and offer the most natural fit for IPP projects.

As a result, utility subsidiaries may own up to 18,000 MW of NUG capacity in the mid-1990s. By the late 1990s, the largest utility players may control NUG project portfolios around 4000 MW. To strengthen their positions, the subsidiaries will purchase projects from non-utility developers up to the maximum allowed.

Eager utilities

Several utilities are anxious to get involved in the NUG business, and, although they will have to play catch-up, they can succeed as long as they strike the right business alliances and pursue projects that fit their skills.